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Fungible Distribution Tariffs: Supporting Distributed Generation Without Bankrupting the Utility

By
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Distributed generation is suddenly receiving a lot of attention. The comments are not all consistent, either with each other or with the physics of the electric network.[1]

Some states have enacted net metering laws. Net metering involves watt-hour meters running backwards when distributed generation is greater than local load. Net metering essentially sets the price for distributed generation equal to the utility's retail tariff.

San Diego Gas & Electric points out in testimony filed in Docket R.99-10-025 that distributed generation does not always lead to a reduction in distribution plant investment, and that any investment savings is not KW for KW.

FERC has taken a more extreme position, allowing a utility to charge a fee for distributed generators delivering electricity into the distribution grid. And recent improvements in magnetic storage seem more useful for providing reactive power to support local voltages instead of real power.

I believe that there are many issues that need to be considered. I begin with the proud boast of the engineering community that the North American electric grid is the largest machine in the world. Utilities may no longer be vertically integrated financially, though many still are; but the machine called the electric grid is still vertically integrated physically.

We need to recognize that distributed generators are part of this vertically integrated machine. This is particularly important when we set competitive prices that are applicable to distributed generation and to customers who seek competitive prices on the distribution grid.

Though the ownership may be limited vertically, prices are still set in a vertical manner. We pay money to people who provide us electricity. We get paid by the people to whom we provide electricity. This should be true for producers, end users, and each owner of wires in between.

Second, we must recognize that distributed generation is not quite the same as a negative load. For most sales tariffs, we can continue to rely on standard load shapes in setting prices for large classes of customers. Distributed generation does not follow any standard pattern. Thus, distributed generation does not offset the load pattern for a retail load. Net metering is not quite the way to go. Net metering also prevents distributed generation from getting any benefit from the price spikes that began occurring in June 1998.[2] Sales of electricity

[1] The concepts presented in this article originally appeared as Mark B. Lively, "Distributed Generation: Setting a Fair Price in the Distribution Tariff," *Public Utilities Fortnightly* (October 15, 2000).

[2] See Mark B. Lively, "Electricity Is Too Chunky: The Midwest Power Prices Were Neither Too High Nor Too Low. They Were Too Imprecise," *Public Utilities Fortnightly* (September 1, 1998).

at $2,000/MWH can be profitable to the owner of a distributed generator, generally even more lucrative than the concept of net metering.

Third, distributed generation is a competitive enterprise, competing with the rest of the electrical grid; at least it should be treated as such. Distributed generation competes with central station power, it competes with transmission, and it competes with the distribution system. This competition is best evaluated on a real time basis, since long-term contracts and standard-offer tariffs are really covered hedges.

We need to recognize the competitive market in which distributed generation operates when we set prices that are to be applicable to distributed generation. We also need to recognize this competitive market as we structure the pricing mechanisms for generation, transmission, and distribution.

Fourth, the competitive prices for distributed generation need not be the same as the prices charged to retail consumers. Most retail consumers are content being served under a standard, embedded cost tariff.

Only those retail consumers who choose the competitive process should face the same competitive market in which distributed generation is evaluated, at least initially. Other retail consumers should be allowed to stay under the standard tariff. Utilities should have two regulated tariffs: one for the competitive market and one for the standard customers.[3] Customers would be permitted to change to the competitive market tariff but not back to the standard tariff.

Fifth, the most obvious part of the competitive process is for generation. But the whole network should be part of the competitive process. For instance, central station generators have always competed against each other, but this competition has reflected the cost the transmission system. In this manner, utility power pools have long used transmission cost data in its economic dispatch on a minute-to-minute basis to achieve the competitive goal of cost minimization while maintaining the desired level of reliability.

The move toward competition has introduced the related concept of power auctions to complement cost-based economic dispatch. These auctions must reflect the location of generators and the cost of connecting remote generation to load centers.

Sixth, the prices for distributed generators should recognize their role in competing against central station power and the transmission grid. However, because the class of distributed generators includes thousands or tens of thousands of small units embedded in the distribution system, the explicit inclusion of distributed generation in traditional economic dispatch or traditional auctions may be impractical. Thus, the generation and transmission portion of any price applicable to distributed generators should be derived from a central dispatch or auction.

[3] See Mark B. Lively, "Competitive Electricity Prices by Changing Tariffs, Not By Changing Providers," *The Washington, D.C. Customer Choice and Utility Competition Report*, prepared for the District of Columbia Office of the People's Counsel Conference on Utility Competition: What Is It And Why Should I Care? May 5, 1998.

One possible derivation of the generation and transmission portion of the distribution price is the price paid for dump power, deviations from the scheduled dispatch. Such dump power prices must be geographically adjusted for transmission issues. Geographically differentiated dump power prices can also be determined through a continuous auction of electricity imbalances.[4]

The industry generally uses the term dump power to refer to excess generation during off-peak periods when generators are experiencing operating problems due to minimum load conditions. The concept is equally applicable to excess generation during the middle of the day, or when the marginal price of electricity zooms to $5,000/MWH.

Seventh, distributed generation can allow utilities to defer distribution system upgrades, which many consider to be the major source of avoidable cost in regard to the distribution system. But distribution upgrades are lumpy investments triggered by uncertain projected demands for electricity. The presence of distributed generation makes the planning process even more uncertain.

But some studies suggest that electrical losses on the distribution system are more costly than system upgrades. At least one utility, Central Vermont Public Service, has justified to its commission the concept of system upgrades just to reduce the cost of distribution losses. Thus, a real time recognition of the savings associated with loss reduction may be as lucrative to distributed generation as proving the distributed generation has caused a deferral of distribution system upgrades.

Background

Central station power plants allowed utilities to reduce their capital and operating costs through various economies of scale: less investment per kilowatt of firm power; lower heat rates and fuel costs; and, fewer people required per kilowatt to operate the power plants.

The development of gas turbines and the increasing availability of natural gas are conducive to distributed generation, generators physically located on the distribution grid or in isolated areas. At the same time that engineers are improving the physics of generation, financiers are seeking to improve their access to the economics of generation through the independent ownership of generation, breaking the seeming monopoly held by electric utilities.

Utilities nominally still have a monopoly on the distribution of electricity. For instance, only utilities are granted the rights-of-way necessary to string transmission lines and distribution lines.

The rights to string wires have not guaranteed the utility the benefits of a monopoly. Customers have always been able to own their own generation. But now, increasingly, third parties are allowed to own generation at a customer's site and make retail sales to the customer. These distributed generators are just not allowed to string wires on public land, at least not in most locations.

As the technology and impetus for distributed generation improve, utilities are diversifying, attempting to invest in non-regulated activities. Some utility

[4] See Mark B. Lively, "Daily Cashouts of Gas Imbalances Using A Formulary Auction," *National Regulatory Research Institute Quarterly Bulletin*, Vol. 20, no. 3 (Fall/Winter 1999): 253-71.

companies, realizing that their forte is electricity, are investing in distributed generation in the service areas of other utilities.

Self-Dealing and Market Dynamics

Several reasons have been presented for a utility affiliate to forego investing in its own service area. A populist excuse is to avoid internal competition, that is, preventing the non-regulated distributed generation enterprise from competing with the regulated utility enterprise.

I believe that a more compelling reason for non-affiliates to avoid building distributed generation in the service area of their affiliated utility is the avoidance of the regulatory quagmire associated with self-dealing.

A regulatory body often views any utility interaction with an unregulated affiliate as unduly favoring the unregulated affiliate. Profits of the unregulated affiliated generator are then construed as having been earned due to actions of the utility. The regulatory body then reduces the utility's allowed earnings by these unjust transfers of profits. The shareholder would then be placed in the worst of all regulatory worlds: any unregulated profits are used to reduce utility rates; and, any unregulated losses are born by the shareholder.

The utility has a simplistic way around the regulatory quagmire. The utility affiliate can avoid distributed generation investment in the utility service area. A second way around the regulatory quagmire is to have all transactions between the utility and the affiliated distributed generation made pursuant to a very explicit filed tariff. For instance, no questions are raised about subsidies when an affiliate buys electricity under the standard tariff for electricity used at office buildings, at least if that standard tariff is open to all potential consumers.

The Need for Dynamic Prices

Any filed tariff used for affiliate dealings must not only be open to all comers, but it must be much more explicit than the "avoided cost" standard associated with the Public Utilities Regulatory Policy Act of 1978 (PURPA). At the same time, a filed tariff for distributed generators must reflect market conditions at the time the power is delivered, not anticipated market conditions.

The value of electricity is constantly changing with the balance between supply and demand. Demand changes slowly throughout the day. Supply often changes suddenly as a generator is forced off line or a contract begins or ends with a neighboring utility. The standard offers for qualifying facilities of the 1980s did not have prices that reflected the market for electricity concurrent to the delivery of power. As a result, the market became cloyed with PURPA machines.

The PURPA tariffs took a static approach to the dynamic electricity market. Utilities need a dynamic price for those entities that want to operate in a competitive market.[5] Now I describe how such a market-maker tariff can handle the distribution network, including distributed generation.

Utilities are no longer monopolies. PURPA stopped the alleged monopoly in terms of their generating function. I say

[5] I proposed such a market maker tariff generically in "Competitive Electricity Prices By Changing Tariffs, Not By Changing Providers," *op. cit.*

alleged because any interconnection between utilities meant that some of the generation used to serve customers would come from a generator owned by some entity in which the utility did not have a financial interest.

PURPA had a bigger effect on the nominal transmission monopoly, since large users of electricity now could more effectively bypass the transmission grid by bringing the generator to the site of the consumption. Distributed generation is similarly destroying the distribution monopoly, allowing small consumers to get their electricity from on-site generation.

With the utility no longer having a monopoly in the delivery of electricity to small consumers (they can self generate with distributed generation), the traditional pricing of distribution services is less applicable.

For customers who desire traditional vertical utility service, cost-based pricing of the distribution system can still work. But, when the distribution service faces competition in the form of distributed generation, another pricing mechanism is warranted, a pricing mechanism that reflects the competitive process: the competition between the utility's ownership of the wires and the operation of distributed generation.

Rather than regulating the price and earnings of the utility, the regulator needs to be regulating the market, the prices at which electricity is bought and sold in the utility's service area.

Why Use A Market-Maker Tariff?

I created the concept of a market-maker tariff in response to the threat of Prodigal customers. The advent of a competitive market has drawn many customers away from the traditional utility supplier with the lure of market rates lower than the average cost rates charged by utilities. But the savings in the competitive market are transitory. The rates are low for a while, then high for a while, at least relative to the average cost rates charged by utilities.

Some customers return to the utility when they find that the competitive market has reversed and has changed into a seller's market. In a seller's market, prices are much greater than the utility's average cost rates. The utility's cost to serve the Prodigal customer must be borne by someone, typically the rest of the utility's customers, the "stick-in-the-muds" who don't choose to choose. Regulators try to protect these customers. In doing so, regulators may force the cost of returning Prodigal customers onto the utility's shareholders. I would instead charge the Prodigal customer.

The return of a Prodigal customer may not seem to be a concern, unless it is a very large customer. As the competitive market becomes more liquid, marketers have found that they can make money during the buyer's market, offering rates low enough to attract customers but still greatly above the depressed market price. When the market price rebounds, these market arbitragers turn back their customers to the utility en masse, multiplying the Prodigal customer issue by the thousands. This has already occurred in the Philadelphia Electric Company (PECO) service territory. During Spring 2000, PECO overnight found itself with 35,000 Prodigal customers that had been turned back to it just as the high cost summer period was beginning.

When a Prodigal customer returns, the utility is faced with buying electricity in the same high cost market that drove the Prodigal back to the utility. These high costs can be treated in three ways: be recovered from all customers, especially those who chose not to choose; be borne by the shareholders of the utility; or, be directly charged to the Prodigal customer through a special tariff, what I call a market-maker tariff.

I suggest a market-maker tariff for all competitive flows of electricity on a utility, including purchases from distributed generations, interaction with affiliated generators, and sales to customers who want to leave the protection of average cost electricity rates. The latter category of transactions includes supplemental power, backup power, standby power, and sales to Prodigal customers. The willingness of the utility to buy electricity from any distributed generator at the prices produced by the market-maker tariff makes affiliated purchases under the market-maker tariff less suspect. I have written elsewhere about pricing imbalance electricity. Here I deal with how to design the distribution portion of a market-maker tariff.

Competitive Markets

By having the distribution portion of the market-maker tariff available to both users and suppliers of electricity on the distribution system, the regulatory authority creates a competitive tension for the utility. High market prices favor suppliers such as distributed generators, encouraging growth in the distributed generation market, which takes market share away from the utility. Low market prices favor the consumer.

The utility can obtain benefits from both high market prices and from low market prices, depending upon its supply position. If the utility is a net buyer of electricity, low market prices reduce the utility's cost with no effect on revenue, thus increasing profits. If the utility is a net seller of electricity, high market prices increase profits. The price for electricity on the distribution system must change to reflect the competing interests of these three participants in the market: suppliers, customers, and the utility.

The market-maker tariff concept is distinguished from the forward or futures market associated with most electricity tariffs as discussed in the Appendix A, "Tariffs as Futures Contracts." The market-maker tariff produces a spot price for electricity, one that changes continuously as the market conditions change. A surplus of distributed generation as the result of high prices will push the distributed portion of the market-maker tariff down. A surplus of consumption as a result of low prices will push the distribution portion of the market-maker tariff up. These competitive pressures are more effective as prices change more frequently than annual rate cases.

For the purposes of this paper, I have assumed that the utility has a mechanism to set a price for dump power, imbalance power delivered to the distribution substation. This dump power price can be considered to be the transmission market price. In my examples, I generally will use the dichotomous prices of \$20.00/MWH and \$2,000.00/MWH, though I give examples using a range of prices.

The price for dump power will of course sometimes be lower than \$20.00/MWH, such as during nighttime hours in the spring and fall. And dump power prices could sometimes be higher than \$2,000.00/MWH, as has been experienced in the Midwest during the Summers of 1998, 1999, and 2000 and elsewhere recently.

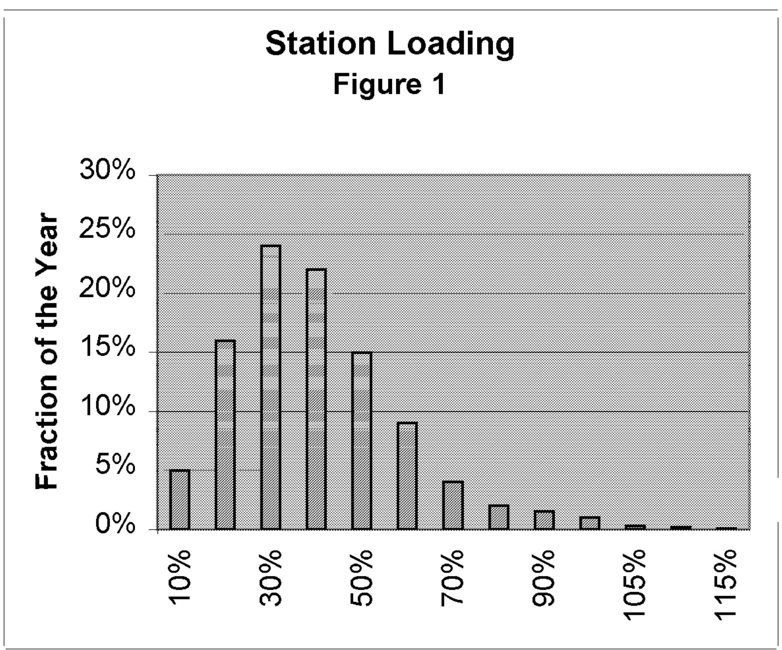
Distribution Station Utilization

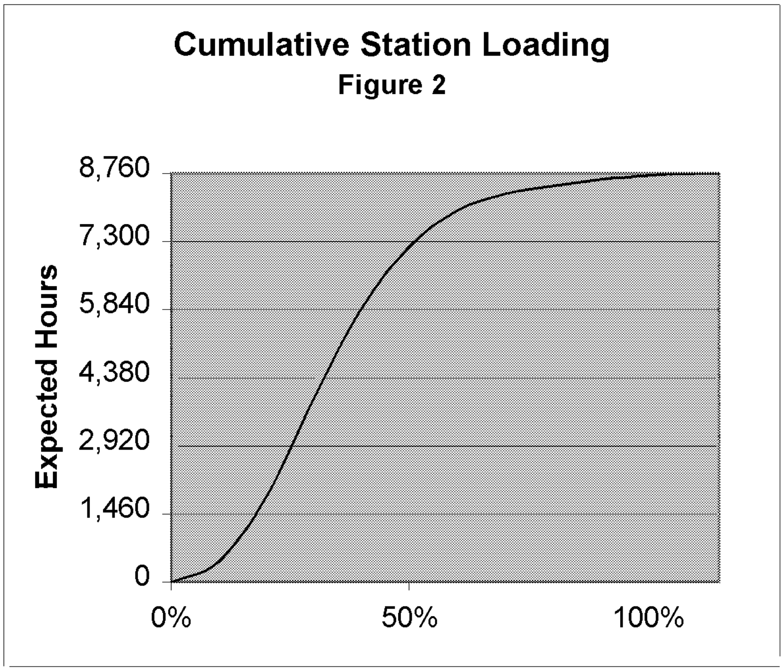
Distribution stations are woefully underutilized. This is generally the result of very low load factors for residential and commercial customers, especially such customers with heavy air conditioning loads, though heating loads can also lead to low load factors on distribution systems.

Figure 1 presents a typical histogram of the utilization of a distribution station. The height of each bar represents the fraction of the year that the distribution station is expected to be at that loading level. For example, we expect that the distribution station will be loaded at 30% of its nominal capability for 24% of the year. The data in this example result in an annual load factor on the distribution station of 39.89%.

Figure 1 is fairly typical for a distribution station serving residential and commercial customers, though much below the annual load factor on a distribution station serving an industrial customer. The annual station loading information is also shown in Figure 2, but on a cumulative basis. Both Figure 1 and Figure 2 reflect an expectation that the distribution station will experience short periods during which the loading exceeds the nominal station capacity.

Though the data presented in Figure 1 and Figure 2 indicate the distribution station is poorly utilized, recent studies suggest that costs are minimized at such low utilization levels. There is a trade-off between the cost of capacity and the cost of energy losses, as will be discussed in passing later in this article.





A Competitive Market on the Distribution System

The market for distributed generation should depend upon the price for imbalance power at the distribution substation, a transmission market price referred to above as a price for dump power. Absent constraints on the distribution system, distributed generators should be competing with central station power, as reflected in the price for dump power at the distribution station.

In a competitive market, why pay distributed generators more or less than the price that can be paid for central station power? Losses. Electrical losses, that is. The transmission of electricity does have the physical cost of electrical losses in wires and transformers.

Electrical losses nominally increase with the square of the power flow. Tripling the flow on the network will cause electrical losses to be nine times as large. The electric utility industry uses the concept of marginal line losses in the optimization of the dispatch of generators.

The tripling of the flow on the network would triple the price differential across the network. Because this triple price differential is charged against three times the flow, the revenue associated with the losses increases by nine times, just as the losses increased by nine times. Thus, price differentials driven by the load on the network provide revenues similar to the costs the utility is incurring for losses.

The line losses vary greatly on any distribution system, generally as stated above with the load on the distribution system. Similarly line losses vary from one distribution system to another. For demonstration purposes, I will use 10% as the anticipated marginal maximum line loss on a hypothetical distribution system. The actual marginal maximum line loss on distribution systems have been estimated to be as low as 2% and as high as 15%.

Based on this hypothetical 10% maximum marginal line loss, the distribution part of a market-maker tariff should result in a price on the distribution system between 90% and 110% of the price for dump power. The 90% and 110% limits reflect the 10% marginal loss factor. A payment within those limits results in net distribution revenue of less than the specified maximum marginal loss factor.

When the distribution station is at its nominal rating receiving power from the grid, the market price on the distribution system is 110% of the postulated dump power price of $20.00/MWH or $22.00/MWH. During periods of high central station prices, the market price on the distribution system is 110% of the dump power price of $2,000.00/MWH, or $2,200.00/MWH.

Conversely, when the distribution station is at its nominal rating delivering power to the grid, the price paid on the distribution system is 90% of the dump power price of $20.00/MWH, or $18.00/MWH. During periods of high dump power, the market price on the distribution system is 90% of $2,000.00/MWH, or $1,800.00/MWH.

Total electrical losses increase with the square of the power flow. Prices are based on marginal electrical losses. The combination of these two concepts will result in net income to the utility nominally equal to half of the charge for electrical losses. The mathematics for this concept is discussed in Appendix B, "Electrical Losses," including a simple numerical example.

Under the above assumptions, the charge for peak time use of the distribution system rated at 10 MW would be equivalent to charging for 1 MW, the maximum marginal loss factor times the capacity of the distribution system. In contrast, though, the actual losses on the system would only by 0.5 MW, as is discussed in Appendix B.

At a dump power price of $20.00/MWH, the 1 MW represented by the marginal loss factor is worth $20 per hour. At the same dump power price, the actual total losses of 0.5 MW results in the utility incurring a cost of $10 per hour for electrical losses. The utility would be earning $10 per hour for the energy it was delivering.

At a dump power price of $2,000.00/MWH, net revenue during periods of high central station prices, the utility would be collecting $2,000 per hour, incurring a cost of $1,000 per hour, and earning $1,000 per hour.

A market maker rate for distribution services could use formula (1):

Formula 1 for Distribution Payment

DP * MMLL * SL

Where:
DP = Dump Power rate ($/MWH)
MMLL = Maximum Marginal Line Loss factor (%)
SL = Station Load factor (%)

The Dump Power rate and the Station Load factor are the values concurrent to the delivery of the electricity in question. The Maximum Marginal Line Loss factor is predetermined seasonally or annually by the distribution network.

Note that the price calculated by Formula 1 is a payment to distributed generators located on a distribution network so long as the Station Load factor is positive, that is, with power flowing into the station from the transmission grid. This payment is by the distributed generators when the Station Load factor is negative, that is, with power flowing from the station into the transmission grid.

The assumed maximum losses are the 10% that I have been using in the example. The annual revenue by the utility under this distribution payment will depend on a complex interaction between the dump power rate and the loading on the distribution network, which I will present on a simplified basis later. The annual revenue by the utility will be proportional to the factor identified as the maximum marginal loss factor on the distribution network.

Sales Rate Differential

The market price for distributed generation needs to be slightly different from the market price for customers purchasing competitive power on the grid. The utility incurs electrical losses in moving electricity from the distributed generator to the consumer, losses that are over and above the losses modeled in the price produced by Formula 1.

The need for such a pricing differential is best demonstrated in the special case of distributed generation meeting the entire needs of all customers on a distribution grid, including losses. The net flow on the substation would then be zero, and the distribution grid could be operated as an electrical island. The price for distribution services would be zero, due to the third factor in Formula 1. But we know that the distribution grid would still be experiencing electrical losses, losses that the utility must supply and pay for. The losses would be the difference between the metered generation and metered sales. Use of the same price for both would cause the utility to lose money.

The actual losses on a distribution network will not perfectly agree with Formula 1. Formula 1 is merely a pricing approximation for the losses that will be incurred. Formula 1 does not reflect the high level of losses associated with minimum load. Formula 1 also does not reflect the high level of losses associated with distributed generators balancing the loads on the distribution grid. Accordingly, Formula 1 can be supplemented with Formula 2.

Formula 2 for Usage Charge

DP * U

Where:
DP = Dump Power rate ($/MWH)
U = Usage factor (%)

The Dump Power rate is the value concurrent to the delivery of the electricity in question. The Usage factor is predetermined seasonally or annually by the distribution network

The concepts presented in Formula 1 and Formula 2 can be combined to develop prices for electricity delivered on the distribution grid. Table 1 is built on the assumption that the transmission market price for electricity is $20/MWH. When the transmission market price for electricity is $2,000/MWH, all of the prices in Table 1 increase by a factor of 100, due to DP being

Table 1: Market-Maker Rates
For Sample Distribution System

Station Load (a)	Distribution Payment (b)	Usage Charge (c)	Sales Rate (d)	Purchase Rate (e)
105%	$2.10	$0.80	$22.90	$22.10
100%	$2.00	$0.80	$22.80	$22.00
95%	$1.90	$0.80	$22.70	$21.90
50%	$1.00	$0.80	$21.80	$21.00
0%	$0.00	$0.80	$20.80	$20.00
-50%	-$1.00	$0.80	$19.80	$19.00
-95%	-$1.90	$0.80	$18.90	$18.10
-100%	-$2.00	$0.80	$18.80	$18.00
-105%	-$2.10	$0.80	$18.70	$17.90

Assumes: $20/MWH Dump Power price
10% Maximum Marginal Line Loss
4% Usage rate
(a) SL in Formula 1
(b) Per Formula 1
(c) Per Formula 2
(d) Dump Power price + Col. (b) + Col. (c)
(e) Dump Power price + Col. (b)

the first factor in both Formula 1 and Formula 2.

The data of Table 1 can be interpreted as follows. The dump power market for the entire table is $20/MWH. The distribution system has a maximum marginal loss factor of 10% and a charge for usage of 4%. The third line of the table is for distribution system loading equal to 95% of its capacity. (Col. (a)) Under these conditions, distributed generators would be paid a premium of $1.90/MWH over the dump power market. (Col. (b)) Consumers would pay a premium of $0.80/MWH over any price paid to distributed generators. (Col. (c)) Consumers would pay $22.70/MWH. (Col. (d)) Distributed generators would experience total revenue of $21.90/MWH (Col. (e)).

Constrained Distribution Systems and a Competitive Market

The station capacity rate in Table 1 is shown as varying between minus 105% (where electricity is being exported from the distribution network to the transmission grid) and plus 105%. Utilities do not plan to operate their distribution on a sustained basis at a loading level in excess of the station's nominal capacity.

Instead, utilities plan to strengthen their distribution systems before load levels increase beyond the nominal capacity of the distribution system. But utilities also know that they are not always able to plan their distribution upgrades in time to match the growth in load. Thus, utilities have protection equipment to open circuit breakers, shutting down parts of the distribution grid when the distribution grid is overloaded.

Developing the set point for protection equipment is an art. However, the set point is generally at a transfer level in excess of the distribution system's nominal capacity. For instance, short periods of overload are acceptable on distribution facilities, in that the excess heat only accumulates slowly in the equipment. Utilities have fans to cool station transformers.

During periods of overload on a distribution system, the value of distributed generation is much greater than the market value of electricity entering the distribution system. Formula 3 presents a way to reflect this increased value.

Formula 3 for Overloads

$$(DP + F1)*2^{[SL-1]/C1}$$

Where:
DP = Dump Power rate ($/MWH)
F1 = Value of Formula 1
SL = Station Load factor (%)
C1 = Constant relating overloads to each doubling of the price paid to distributed generators

The Dump Power rate, Formula 1, and the Station Load factor are the values concurrent to the delivery of the electricity in question. The Constant relating overloads to each doubling of the price paid to distributed generators is predetermined.

Sometimes the distributed generation might be so large that the distribution system is overloaded delivery electricity to the transmission system. During such periods of overload on a distribution system, the value of distributed generation is much less than the value of dump power. Formula 4 presents a way to reflect this decreased value.

Formula 4 for Overloads

$$(DP + F1)*2^{[SL+1]/C2}$$

Where:
DP = Dump Power rate ($/MWH)
F1 = Value of Formula 1
SL = Station Load factor (%). A negative Station Load factor indicates that the distribution system is delivering electricity to the transmission system.
C2 = Constant relating overloads to each halving of the price paid to distributed generators

The Dump Power rate, the value of Formula 1, and the Station Load factor are the values concurrent to the delivery of the electricity in question. Note that the value of Formula 1 is determined from the Dump Power rate and the Station Load factor. The Constant relating overloads to each halving of the price paid to distributed generators is predetermined. Generally, C2 will be set equal to C1 used in Formula 3.

The market maker price for when the distribution station is in its nominal operating range is the same in Table 1 as in Table 2. However, when the distribution system is nominally overloaded, the market-maker rate provides incentives for market sensitive customers to react to the overloads.

The data of Table 1 can be interpreted as follows. The dump power market for the entire table is $20/MWH. The distribution system nominally has a maximum marginal loss factor of 10% and a charge for usage of 4%. The first line of the

Table 2: Market Maker Rates
For Constrained Distribution System

Station Load	Purchase Rate Nominal	Purchase Rate Market	Usage Charge	Sales Rate	Wheeling Charge
(a)	(b)	(c)	(d)	(e)	(f)
115%	$22.30	$63.07	$0.80	$63.87	$43.87
110%	$22.20	$44.40	$0.80	$45.20	$25.20
105%	$22.10	$31.25	$0.80	$32.05	$12.05
100%	$22.00	$22.00	$0.80	$22.80	$2.80
95%	$21.90	$21.90	$0.80	$22.70	$2.70
50%	$21.00	$21.00	$0.80	$21.80	$1.80
0%	$20.00	$20.00	$0.80	$20.80	$0.80
-50%	$19.00	$19.00	$0.80	$19.80	-$0.20
-95%	$18.10	$18.10	$0.80	$18.90	-$1.10
-100%	$18.00	$18.00	$0.80	$18.80	-$1.20
-105%	$17.90	$12.66	$0.80	$13.46	-$6.54
-110%	$17.80	$8.90	$0.80	$9.70	-$10.30
-115%	$17.70	$6.26	$0.80	$7.06	-$12.94

Assume: $20/MWH Dump Power price
10% Maximum Marginal Line Loss
4% Usage rate
C1=C2=10%, i.e., prices double for each 10% overload

(a) SL in Formula 1, Formula 3, and Formula 4
(b) Per Formula 1
(c) Per Formula 3 or 4
(d) Per Formula 2
(e) Col. (c) + Col. (d)
(a) Col. (e) - Dump Power price

table is for distribution system loading equal to 115% of its nominal capacity. (Col. (a)) That is, the distribution system is overloaded and needs some relief.

Under the conditions mentioned above, distributed generators would be paid a price of $63.07/MWH. (Col. (c)) This is a premium over the nominal price of $22.30/MWH (Col. (b)). The nominal price reflects the dump power price plus losses.

The premium is a part of the market incentive to reduce the loading on the distribution network.

Consumers would pay a premium of $0.80/MWH over any price paid to distributed generators. (Col. (d)) Consumers would pay $63.87/MWH. (Col. (e)) Consumers with their own energy supplies off the distribution system would pay $43.87/MWH as a wheeling charge for the use of the distribution network (Col. (f)).

The distribution system can be nominally overloaded with electricity leaving the system, such as during the middle of the night when loads are low and distributed generators are producing more electricity than the capacity of the network. During these periods, there needs to be market pressure on the distributed generators to reduce the production of electricity. This market pressure is accomplished by lowering the distribution market price of electricity below the transmission market price of electricity.

Combining the Parts

In Figure 1 and 2, I presented the variation in the loading of a typical distribution station. In Table 3, I present this variation in numeric form, including the development of the annual station loading factor of 39.89%.

Note that as station loading increases, the customer load as a fraction of station load decreases. Not only do losses increase as the station loading increases, but

Table 3: Typical Distribution Station Loading Data

Station Loading Relative (a)	Station Loading MW (b)	Customer Load MW (c)	Annual Frequency (d)	Weighted Load Data: Station Loading Relative (e)	Weighted Load Data: Station Loading MW (f)	Weighted Load Data: Customer Load MW (g)
10%	1.0	0.995	5.00%	0.50%	0.0500	0.0498
20%	2.0	1.980	16.00%	3.20%	0.3200	0.3168
30%	3.0	2.955	24.00%	7.20%	0.7200	0.7092
40%	4.0	3.920	22.00%	8.80%	0.8800	0.8624
50%	5.0	4.875	15.00%	7.50%	0.7500	0.7313
60%	6.0	5.820	9.00%	5.40%	0.5400	0.5238
70%	7.0	6.755	4.00%	2.80%	0.2800	0.2702
80%	8.0	7.680	2.00%	1.60%	0.1600	0.1536
90%	9.0	8.595	1.50%	1.35%	0.1350	0.1289
100%	10.0	9.500	1.00%	1.00%	0.1000	0.0950
105%	10.5	9.949	0.26%	0.27%	0.0273	0.0259
110%	11.0	10.395	0.18%	0.20%	0.0198	0.0187
115%	11.5	10.839	0.06%	0.07%	0.0069	0.0065
Totals			100.00%	39.89%	3.9890	3.8920

Assume: 10 MW Station Capacity
10% Maximum Marginal Loss Factor
Annual Frequencies as shown in Figure 1

(a) SL as used in Formulas 1, 3, and 4
(b) 10 MW times Col. (a)
(c) Col. (b) minus losses calculated as Col. (b) * Col. (b) / 200
(d) From Figure 1
(e) Col. (a) * Col. (d)
(f) Col. (b) * Col. (d)
(g) Col. (c) * Col. (d)

the fraction of the station loading that is consumed by losses increase, because of the increasing losses being incurred for the operation of the distribution system. The average loss factor is 2.43% of energy entering the station from the transmission system.

In the text of this article, I have referred to dump power prices on a dichotomous basis, either as $20.00/MWH or $2,000.00/MWH. Dump power prices are not dichotomous. The prices of dump power should be almost a continuous function. I show a range of prices in Table 4 in an evaluation of the market price of electricity at the transmission side of the distribution station.

Generally, dump power prices will be low when the station is lightly loaded. I have adopted $20.00/MWH as the dump power average price for the lower loading levels. I then increase the dump power prices to $50.00/MWH, $100/MWH, and then jump to $2,000.00/MWH.

Table 4: Development of Average Market Prices

Station Loading Relative	MW	Annual Frequency	Dump Price	Weighted Dump Price	Weighted Loading	Load Weighted Price
(a)	(b)	(c)	(d)	(e)	(f)	(g)
10%	1.0	5.00%	$20.00	$1.00	0.0500	$1.00
20%	2.0	16.00%	$20.00	$3.20	0.3200	$6.40
30%	3.0	24.00%	$20.00	$4.80	0.7200	$14.40
40%	4.0	22.00%	$20.00	$4.40	0.8800	$17.60
50%	5.0	15.00%	$50.00	$7.50	0.7500	$37.50
60%	6.0	9.00%	$50.00	$4.50	0.5400	$27.00
70%	7.0	4.00%	$50.00	$2.00	0.2800	$14.00
80%	8.0	2.00%	$100.00	$2.00	0.1600	$16.00
90%	9.0	1.50%	$100.00	$1.50	0.1350	$13.50
100%	10.0	1.00%	$100.00	$1.00	0.1000	$10.00
105%	10.5	0.26%	$2,000.00	$5.20	0.0273	$54.60
110%	11.0	0.18%	$2,000.00	$3.60	0.0198	$39.60
115%	11.5	0.06%	$2,000.00	$1.20	0.0069	$13.80
Totals				$41.90	3.9890	$265.40
Average					$66.53	

Assume: 10 MW Station Capacity
Annual Frequencies as shown in Figure 1
Dump Power prices as discussed in text

(a) SL as used in Formulas 1, 3, and 4
(b) 10 MW x Col. (a)
(c) From Figure 1
(d) See discussion in text
(e) Col. (c) x Col. (d)
(f) Col. (b) x Col. (c)
(g) Col. (d) x Col. (f)

The average dump power price delivered to the distribution station depends on the weighting factor. The average price is $41.90/MWH, when weighted by the fraction of the time each of the prices are applicable. This would be the price experienced by a base loaded generator sited at the transmission station. However, when these prices are weighted by the amount of energy delivered to the distribution station, as developed in the last two columns of Table 4, the average price jumps to $66.53/MWH. This would be what the utility would have to pay for power it receives into the distribution station.

The time-weighted price for dump power in Table 4 is $41.90/MWH. The load-weighted price for dump power in Table 4 is $66.53/MWH. The difference between these two average prices is indicative of some of the subsidies that exist on the electric system. I have long argued that the biggest form of subsidy is inter-temporal, especially within a class.

Normally customers receive subsidies during the very peak period, paying less than the market value of electricity. These subsidies during very peak period are covered during off-peak periods. Generally the same customers that receive the subsidies during the peak periods provide the subsidies during the off-peak period. The cessation of these inter-temporal subsidies caused the high prices experienced by customers in San Diego during July 2000.

The introduction of competition has broken the normal subsidy linkage between the peak and the off-peak periods. Prodigal customers escape the system during the off-peak period and avoid contributing to the subsidy. Prodigal customers return during the peak period, wanting to eat at the subsidy trough to which they did not contribute during the off-peak period. After all, the Prodigal customers were buying from a marketer during the off-peak period, not from a utility.

The dump power prices presented in Table 4 have a strong impact on the charge for using the distribution system, the inbound distribution charged developed in Table 2. I show a range of these prices in Table 5. The market sales rate is developed from the market price plus losses and the sales charge of 4%. For station loadings in excess of 100%, the joint dispatch procedure presented in Formula 3 has been used to increase the price from the nominal sales rate.

The average prices in Table 5 reflect the assumed annual frequency distribution for the station loading, but not the loading itself. Thus, the average market sales rate of $55.05/MWH is the average price experienced by a customer with a load factor equal to 100%, or a least a customer whose energy consumption has no seasonal or diurnal pattern.

The inbound distribution charge would be paid by a customer whose load pattern is equivalent to load factor of 100%. Note that the inbound distribution charge of $13.15/MWH is the difference between the market price of $41.90/MWH and the market sales rate of $55.05/MWH.

The net income that the utility would earn if all customers were served under a fungible distribution tariff is presented in Table 6. The utility would incur cost at the distribution station based on the loading at the distribution station and the prices at the distribution station. The annual frequency determines the weighted load, which is then priced using the data from Tables 4 and 5.

Table 5: Distribution of Prices on Distribution System

Station Loading (a)	Annual Frequency (b)	Dump Price (c)	Distribution Sales Rate (d)	Inbound Distribution Charge (e)
10%	5.00%	$20.00	$21.00	$1.00
20%	16.00%	$20.00	$21.20	$1.20
30%	24.00%	$20.00	$21.40	$1.40
40%	22.00%	$20.00	$21.60	$1.60
50%	15.00%	$50.00	$54.50	$4.50
60%	9.00%	$50.00	$55.00	$5.00
70%	4.00%	$50.00	$55.50	$5.50
80%	2.00%	$100.00	$112.00	$12.00
90%	1.50%	$100.00	$113.00	$13.00
100%	1.00%	$100.00	$114.00	$14.00
105%	0.26%	$2,000.00	$3,205.41	$1,205.41
110%	0.18%	$2,000.00	$4,520.00	$2,520.00
115%	0.06%	$2,000.00	$6,387.39	$4,387.39
Average		$41.90	$55.05	$13.15

Assume: 10 MW Station Capacity
10% Marginal Line Losses at 10 MW
(a) SL as used in Formulas 1, 3, and 4
(b) From Figure 1
(c) See discussion in text
(d) Per Formula 1 + Formula 2 as adjusted by Formula 2 or Formula 4
(e) Col. (d) – Col. (c)

The utility would receive revenue based on the customer load, which is less than the station load by actual losses, assumed to be the equivalent of 10% on a marginal basis at full load. The weighted customer load reflects the annual frequency of those load levels. The prices are the market sales rates from Table 5.

The average load on the distribution system is 3.989 MW into the substation. The utility would incur market costs at an average rate of $265.40 per hour, or $66.53/MWH.

The average sales load by the utility would be 3.8920 MW at the customer meters. Thus, average losses on the distribution grid would be 0.0970 MW, or 2.43% of the energy supplied to the distribution grid by the transmission grid.

The utility would collect revenue at an average rate of $376.85 per hour, or $98.83/MWH. The utility would have net earnings from the distribution grid of $111.45 per hour, or $28.63/MWH of sales.

Table 6: Utility Net Distribution Revenue

		Station Loading Data			Customer Load Data		
Station Loading	Annual Frequency	MW	Weighted MW	Priced At Dump Rate	MW	Weighted MW	Priced At Dump Rate
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
10%	5.00%	1.000	0.0500	$1.00	0.995	0.0498	$1.04
20%	16.00%	2.000	0.3200	$6.40	1.980	0.3168	$6.72
30%	24.00%	3.000	0.7200	$14.40	2.955	0.7092	$15.18
40%	22.00%	4.000	0.8800	$17.60	3.920	0.8624	$18.63
50%	15.00%	5.000	0.7500	$37.50	4.875	0.7313	$39.85
60%	9.00%	6.000	0.5400	$27.00	5.820	0.5238	$28.81
70%	4.00%	7.000	0.2800	$14.00	6.755	0.2702	$15.00
80%	2.00%	8.000	0.1600	$16.00	7.680	0.1536	$17.20
90%	1.50%	9.000	0.1350	$13.50	8.595	0.1289	$14.57
100%	1.00%	10.000	0.1000	$10.00	9.500	0.0950	$10.83
105%	0.26%	10.500	0.0273	$54.60	9.949	0.0259	$82.91
110%	0.18%	11.000	0.0198	$39.60	10.395	0.0187	$84.57
115%	0.06%	11.500	0.0069	$13.80	10.839	0.0065	$41.54
Totals			3.9890	$265.40		3.8920	$376.85
Averages			$66.53			$96.83	

Assume: 10 MW Station Capacity
Prices as shown or calculated in Table 5

(a) SL as used in Formulas 1, 3, and 4
(b) From Figure 1
(c) 10 MW x Col. (a)
(d) Col. (b) x Col. (c)
(e) Col. (d) x Price in Table 5, Col. (c)
(f) Col. (c) less losses
(g) Col. (b) x Col. (f)
(h) Col. (g) x Price in Table 5, Col. (d)

Reactive Power

Engineers and regulators are expressing a growing concern about voltage. Reactive power is the major cause of voltage problems. Reactive power can also be a major issue in the overloading of distribution and transmission lines.

Lagging reactive power, such as power used for electromagnetic motors, reduces the voltage from standard. Leading reactive power, such as used for fluorescent light bulbs, increases the voltage from standard.

Central station generators are used to fine tune the reactive power on the network, but the best solution is for the reactive power to be controlled at the load centers. Hence many utilities have tariffs that encourage customers to improve their power factor.

Distributed generation can provide a good solution for reactive power problems.

For instance, recent tests of super-conducting magnets for energy storage have been touted for their ability to provide and absorb reactive power, not for the their ability to provide active energy.

The standard utility approach for handling low voltage problems on a distribution system is the installation of capacitors. Capacitors provide leading reactive power, canceling out the lagging power in an area and raising the voltage.

But many customer-owned capacitors are not switched. When lagging power use declines in an area, the capacitors continue to operate, causing high voltages. This has been a major concern for utilities on weekends, when large customers turn off their motors but sometimes don't switch off their capacitors.

A fungible distribution tariff would charge a varying price for reactive power that caused voltages to vary from standard and pay the same varying price for reactive power that kept voltages from varying further from standard. There would be no payment for reactive power when the local voltage was at standard, as is demonstrated in formula (5).

Formula 5 for Reactive Power

$$PP*Conv*[2^{(Act/Nom)}-2^{(Nom/Act)}]$$

Where:
PP=Purchase price for DG as developed by previous formulas ($/MWH)
Conv=Conversion factor (VARH/WH)
Act=Actual Voltage
Nom=Nominal Voltage

Notice that when the actual voltage is equal to the nominal voltage the quantity in the brackets is zero and there is no payment for leading or lagging reactive power.

Joint Dispatch

Central station power plants are dispatched to achieve a uniform marginal production cost as adjusted for marginal line losses. The use of a market-maker tariff for the distribution grid achieves the similar results for distributed generation.

Most of the time, the market-maker distribution charge places distributed generation on the same economic footing as central station power, paying for the distributed generation at the transmission rate plus the marginal losses saved by the operation of the distributed generation on the distribution system.

The dispatch algorithms used for central station power often explicitly calculate marginal line losses to move electricity from one power plant to another. The myriad of distributed generators that are now on the distribution system, and their small size, makes an explicit calculation of marginal line losses for each distributed generator impractical. There is thus a need for a market maker tariff with prices that implicitly reflect marginal electrical losses on the distribution system since we cannot do so explicitly.

Some utilities own portable distributed generators as temporary supplements for the capacity of distribution networks. When distribution loads grow faster than utilities expected, these portable distributed generators provide a stopgap until the distribution system can be upgraded.

A fungible distribution tariff would allow the utility to transfer ownership of the portable distributed generators to a non-regulated affiliate, or allow non-affiliates to provide such temporary generating capacity for the utility on an emergency basis, subject to a standard tariff instead of the utility renting the distributed generators.

A fungible distribution tariff would allow a joint dispatch of distributed generators with central station power plants, at least the value of the central dispatch would be paid to the distributed generators. A fungible distribution tariff also allows the joint dispatch of reactive power devices. Distributed generators could vary their power factor to control local voltage levels. The local voltage levels would then depend on the operating cost of the distributed generator to provide the reactive power necessary to correct the problem.

Distribution Wheeling

The usage fee calculated in Formula 2 is the effective charge for distributed generators who want to wheel electricity to a consumer on the same distribution grid. The fee goes up and down with the transmission market price for electricity.

A greater issue for distribution wheeling is temporal imbalances. Electricity has a value that changes continuously. Real time imbalances need to be cashed out at the appropriate market sales rate or market purchase rate. An extra MWH delivered during the middle of the night has a value that is much different from the value of an extra MWH delivered during the middle of the day.

Conclusions

The advent of distributed generation provides an opportunity for utilities to take market concepts to a new level, creating fungible distribution tariffs. Such tariffs would eliminate the need to schedule the myriad of generators now being added to the distribution grid.

A fungible distribution tariff would also encourage consumers with blackout generators to use such generators on a market sensitive basis, contributing power to the grid when the distribution grid is overloaded or when the transmission price of power reaches unusual levels.

A dynamic approach to pricing distribution services can allow a utility to serve the growing supply of distributed generation on a fair basis without unfairly imposing subsidies on customers' purchasing power from the distribution grid. These dynamic prices can be the basis for paying distributed generators for the power they supply to the grid, reflecting marginal line losses and constraints on the network. The recognition of constraints becomes a substitute for a direct assignment of avoided costs, when distributed generation has allowed the utility to avoid the cost of upgrading the distribution system.

Appendix A
Tariffs as Futures Contracts

Most electric utility tariffs and contracts should be viewed and evaluated as covered hedges. A hedge is a futures contract that protects the buyer or the seller of a commodity against the vagaries of the spot market.

Transmission and distribution services should be viewed and evaluated as pairs of covered sales hedges. One of the covered hedges is for the point that the electricity is delivered to the transmission or distribution system. The other covered hedge is for the point that the transmission or distribution system delivers the electricity back to the customer.

Commodities are generally sold under a futures or forward contracts or under a spot contract. (See "Electric Transmission Pricing: Are Long-term Contracts Really Futures Contracts?" *Public Utilities Fortnightly,* 1994 October 15 and "Electric Customer Participation in the Competitive Market: Reliability, Futures Contracts, and Arbitraging," *The National Regulatory Research Institute Quarterly Bulletin*, Winter 1997. The latter paper was developed under contract to the Regulatory Flexibility Committee of the Indiana Legislature for its meeting of 1997 September 9-10. The latter paper was also presented as prepared remarks to the Task Force To Study Retail Electric Competition And The Restructuring Of The Electric Utility Industry of the Maryland General Assembly for its meeting of 1997 November 11.)

Under a futures or forward contract, the seller has time to modify production in order to supply the commodity. For instance, for agricultural commodities a futures contract often specifies delivery after the next harvest. Under a spot contract, the commodity is delivered on the spot, out of inventory before the seller has time to modify production, sometimes even before the seller has time to ship the commodity from a distant location.

There is no inventory of electricity. Generators produce electricity as it is needed. A spot sale of electricity must thus have some meaning other than the delivery of electricity out of inventory. I look at a spot sale of electricity as the delivery of electricity based on the current stock of generators, before any idle generators can be brought into production, or before any unit commitment decisions can be changed.

Some generators can now be brought on line in a matter of minutes. This reduces the concept of spot sales to transactions made for delivery during the next few minutes or seconds or concurrent to the deal being made. Transactions for the next hour or the next day thus should be viewed as futures contracts, as hedges against the spot price of electricity during the specified time period.

When the seller also owns generation or the right to generation, the contract is a covered hedge. Futures contracts have created a whole new branch of financial analysis, requiring special consideration.

A long-term contract to transport electricity across the transmission grid or a distribution grid should be evaluated as two long-term purchase contracts. The purchase contracts are for electricity delivered into or out of the relevant grid at specific locations. Because the utility owns sufficient transmission or distribution assents to provide the service, the wheeling contract should be thought of as a covered hedge.

Appendix B
Electrical Losses

Electric utilities incur electrical losses in the delivery of electricity to their customers. According to Ohm's Law, voltage is the product of the current and resistance. As the current flow increases, the voltage across the resistance increases. The power consumption is the product of the voltage and the current.

Using simple algebra, power can also

be expressed as the square of the current times the value of the resistance, often referred to as I^2R. Alternatively, simple algebra can be used to express power in terms of voltage as V^2/R. For a distribution system, there are two important applications of Ohm's Law and this method for calculating power flow.

The most significant application of Ohm's Law is the usage on the entire distribution grid. Nominally the voltage on the distribution grid is constant. As power through the distribution network increases, V^2/R suggests that the resistance on the network has decreased.

The change in resistance is the result of consumers adding additional devices in parallel to existing devices. Thus, the resistance in the Ohm's Law is not constant for the entire grid as consumers turn devices off and on. But because the voltage is almost constant, the current can be a good proxy for the power flowing on the distribution network.

The actual utility distribution network does not change significantly as consumers add and remove devices. Most importantly, the resistance of this utility distribution network does not change. The total power lost on the distribution grid thus follows the I^2R rule, increasing with the flow of current through the distribution grid and, thus, with the power going through the substation.

The concept of marginal losses deals with the small change in total power losses as a fraction of the change in total power. Using calculus on the I^2R relation, marginal losses are 2IR.

Any charge for marginal losses would be against the total power flowing on the system, which is proportional to I. Thus, charging consumers for losses on a marginal basis collects for $2*I^2R$, which is twice the actual losses incurred for the network.

A numerical example often provides a better way to understand issues initially introduced using formulas. In regard to marginal losses versus total losses, I present three tables. Table B-1 presents power losses for a large range of power levels flowing through the substation.

Power is measured as the product of voltage and current, the latter measured in amperes. Since the voltage at a substation, 12,000 volts in this example, is roughly fixed and constant, the power used in a distribution system is proportional to the current. In Table B-1, the station power value in column (b) is column (a) times 12,000.

The voltage drop on the distribution wires is not fixed and constant. Instead, the voltage drop is proportional to the current on the distribution system. In Table B-1, column (c) is column (a) times 120. This scaling results in the voltage drop being 10% when current is 10 amps. In my example, this would be the capacity of the distribution system, 10 amps in column (a) or 120,000 volt-amps in column (b).

The power loss on the distribution system is the product of the voltage drop and the current. Since the voltage drop is proportional to the current on the distribution system, the power loss on the distribution system is proportional to the square of the current. In Table B-1, column (d) is column (c) times column (a), which is the same as column (a) squared times 120.

Power losses can be expressed as a fraction of total power on the grid. Column (e) is column (d) divided by column (b).

Table B-1: Calculation of Average Losses

Station Current (Amps)	Station Power (V-A)	Voltage Drop (Volts)	Power Losses Total (V-A)	Power Losses Relative (%)
(a)	(b)	(c)	(d)	(e)
1	12,000	120	120	1%
2	24,000	240	480	2%
3	36,000	360	1,080	3%
4	48,000	480	1,920	4%
5	60,000	600	3,000	5%
6	72,000	720	4,320	6%
7	84,000	840	5,880	7%
8	96,000	960	7,680	8%
9	108,000	1080	9,720	9%
10	120,000	1200	12,000	10%

(a) Measured current leaving station
(b) 12,000 volts x Col. (a)
(c) Average voltage drop on the network assuming 10% at 10 MW.
(d) Power Loss associated with the voltage drop and current; Col. (a) x Col. (c)
(e) Col. (d) / Col. (b)

Table B-1 above shows data for current flows for 1 through 10 amps, by 1 amp steps. This provides a general feel for how the losses vary with the usage of the network.

Table B-2 below presents a set of calculations for 3.000 amps through 3.002 amps, by 0.001 amp steps. The small increments allow a better illustration of marginal losses without using calculus. All of the calculations in Table B-2 are the same as the calculations in Table B-1. The only difference is the finer intervals and greater precision of the presentation.

I present a marginal analysis in Table B-3. For the marginal analysis,

- The amps and the voltage drop are averages of the data from Table B-2. Thus, 3.0005 is an average of 3 and 3.001 while 360.06 is the average of 360 and 360.12;
- The grid power and the total distribution losses are increments. Thus, 12 is the difference between 36,000 and 36,012 and 0.72012 is the difference between 1080.000 and 1080.72012; and,
- The loss factor is the ratio of the two incremental numbers.

Notice that marginal losses of about 6%, as approximated by the incremental losses, are twice the average losses of about 3%. If a utility charges marginal losses of 6% and has actual losses of 3%, its net income on this part of the business is equal to its cost.

Table B-2: Calculation of Average Losses at Small Intervals

Station Current (Amps)	Station Power (V-A)	Voltage Drop (Volts)	Power Losses Total (V-A)	Power Losses Relative (%)
(a)	(b)	(c)	(d)	(e)
3	36,000	360.00	1,080.00000	3.000%
3.001	36,012	360.12	1,080.72012	3.001%
3.002	36,024	360.24	1,081.44048	3.002%

(a) Measured current leaving station
(b) 12,000 volts x Col. (a)
(c) Average voltage drop on the network assuming 10% at 10 MW.
(d) Power Loss associated with the voltage drop and current; Col. (a) x Col. (c)
(e) Col. (d) / Col. (b)

Table B-3: Calculation of Marginal Losses at Small Intervals

Station Current (Amps)	Station Power (V-A)	Voltage Drop (Volts)	Power Losses Total (V-A)	Power Losses Relative (%)
(a)	(b)	(c)	(d)	(e)
3.0005	12	360.06	0.72012	6.001%
3.0015	12	360.18	0.72036	6.003%

(f) Measured current leaving station; Average of two numbers in Table B-2.
(g) Difference between two numbers in Table B-2.
(h) Average voltage drop on the network assuming 10% at 10 MW; Average of two numbers in Table B-2.
(i) Power Loss associated with the voltage drop and current; Col. (a) x Col. (c)
(j) Col. (d) / Col. (b)